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Description

Method and System for Determining an Optimum Pumping Schedule Corresponding to an Optimum Return on Investment when Fracturing a Formation penetrated by a Wellbore

CROSS REFERENCE TO RELATED APPLICATIONS

[0001] This application claims benefit of U.S. Provisional Patent Application No. 60/481,623 filed on November 11, 2003.

BACKGROUND OF INVENTION

[0002] The subject matter of the present invention relates to a system and method for real time control of hydraulic fracturing treatments of a formation penetrated by a wellbore, and, in particular, a system and method for determining an optimum pumping schedule which corresponds to an optimum production rate and an optimum return on investment when fracturing a perforated formation pene-

trated by a wellbore.

[0003] When fracturing a formation penetrated by a wellbore, a particular pumping schedule is utilized for pumping fracturing fluid into a plurality of perforations in a formation penetrated by the wellbore. Oil and other hydrocarbon deposits will produce from the fractured perforations in response thereto, the oil and other hydrocarbon deposits flowing uphole. A particular production rate corresponds to the particular pumping schedule, the particular production rate representing the rate at which the oil and other hydrocarbon deposits flow uphole. A particular return on investment corresponds to the particular production rate of the hydrocarbon deposits flowing uphole, the particular return on investment representing the amount of a client"s profits being derived from a producing well in connection with the particular production rate of the oil and other hydrocarbon deposits being produced from the well and flowing uphole in relation to the costs for fracturing and producing that well.

[0004] A client will want to know whether a particular return on investment, associated with a particular production rate and a particular pumping schedule for a single well is an "optimum" one. The term "optimum" is defined by the

client. Therefore, it is desirable to determine in advance for a particular well, before a fracturing operation is completed, whether a selected pumping schedule is an "optimum" pumping schedule which, when utilized, will fracture a well in a particular manner such that oil and other hydrocarbon deposits will be produced at an "optimum" production rate thereby generating an "optimum" return on investment for the client.

SUMMARY OF INVENTION

[0005] One aspect of the invention involves a method of determining a pumping schedule adapted for fracturing a formation penetrated by a wellbore, comprising the steps of: defining a selected pumping schedule to include an initial portion and a remaining portion; interrogating a pump data model in response to at least one of the initial portion and the remaining portion thereby generating a return on investment; deciding if the return on investment is an acceptable return on investment; and determining the pumping schedule to be the initial portion and the remaining portion of the selected pumping schedule when the return on investment is an acceptable return on investment.

[0006] Another aspect of the present invention involves a method

of determining a pumping schedule corresponding to a particular return on investment for a particular wellbore, the pumping schedule including an initial pumping schedule and a remaining pumping schedule, comprising the steps of: (a) fracturing one or more perforations in a formation penetrated by the particular wellbore, thereby creating one or more fractures in the formation, in accordance with the initial pumping schedule; (b) analyzing a set of fracture characteristics associated with the one or more fractures in response to the fracturing step; (c) interrogating a pump data model in accordance with the remaining pumping schedule; and (d) determining a particular return on investment for the particular wellbore in response to the interrogating step, the pumping schedule corresponding to the particular return on investment for the particular wellbore when the pump data model is interrogated in accordance with the remaining pumping schedule.

[0007] Another aspect of the present invention involves a method of determining a return on investment associated with a particular wellbore before completing a fracturing of a formation penetrated by the wellbore, the formation being fractured in response to a particular pumping schedule, a

pump data model generating one or more values indicative of the return on investment when interrogated by at least a portion of the pumping schedule, the method comprising the steps of: (a) before completing the fracturing of the formation, interrogating the pump data model in response to at least a portion of the pumping schedule; and (b) generating one or more values indicative of the return on investment in response to the interrogating step.

[0008] Another aspect of the present invention involves a method of determining a return on investment associated with a particular wellbore before completing a fracturing of a formation penetrated by the wellbore, the formation being fractured in response to a particular pumping schedule, a pump data model generating one or more values indicative of the return on investment when interrogated by at least a portion of the pumping schedule, the method comprising the steps of: (a) calibrating the pump data model; (b) before completing the fracturing of the formation, interrogating the calibrated pump data model in response to at least a portion of the pumping schedule; and (c) generating one or more values indicative of the return on investment in response to the interrogating step.

[0009] Another aspect of the present invention involves a method of determining a pumping schedule adapted for fracturing a formation penetrated by a wellbore, the pumping schedule including an initial pumping schedule and a remaining pumping schedule, comprising the steps of: (a) fracturing the formation penetrated by the wellbore in accordance with the initial pumping schedule thereby generating fractures in said formation; (b) interrogating a pump data model in response to the remaining pumping schedule thereby generating a return on investment; (c) in response to the interrogating step, deciding whether the return on investment is an acceptable return on investment; and (d) in response to the deciding step, determining the pumping schedule to be the initial pumping schedule and the remaining pumping schedule when the return on investment is an acceptable return on investment.

[0010] Further scope of applicability of the present invention will become apparent from the detailed description presented hereinafter. It should be understood, however, that the detailed description and the specific examples, while representing a preferred embodiment of the present invention, are given by way of illustration only, since various

changes and modifications within the spirit and scope of the invention will become obvious to one skilled in the art from a reading of the following detailed description.

Brief Description of Drawings

[0011] A full understanding of the present invention will be obtained from the detailed description of the preferred embodiment presented hereinbelow, and the accompanying drawings, which are given by way of illustration only and are not intended to be limitative of the present invention, and wherein:

[0012] figure 1 illustrates a perforating gun perforating a formation penetrated by a wellbore;

[0013] figure 2 illustrates how a fracturing fluid is pumped into the perforations in the formation and fracturing the formation in accordance with a pumping schedule;

[0014] figure 3 illustrates how oil or other hydrocarbon deposits are produced from the fractured perforations in the formation and flow uphole, the hydrocarbon deposits flowing uphole having a production rate in barrels/day and a return on investment corresponding to the production rate;

[0015] figures 4, 5, and 6 illustrate three separate wells wherein, by way of example, three separate pumping schedules associated with the three separate wells are used before an

"optimum" pumping schedule is realized which corresponds to an "optimum" return on investment;

[0016] figures 7 and 8 illustrate one particular well wherein one pumping schedule is used for the purpose of determining an "optimum" pumping schedule which corresponds to an "optimum" return on investment;

[0017] figures 9 and 10 illustrate three separate "time line merged" inputs that are input to a computer system in a well logging truck situated near the particular well of figures 7 and 8, the three separate inputs being an initial pumping schedule, tiltmeter data originating from sensors disposed near a fracture in a formation, and micro-seismic data also originating from sensors disposed near the fracture in the formation;

[0018] figure 11 illustrates a construction of the computer system in the well logging truck of figures 9 and 10;

[0019] figure 12 illustrates a block diagram representing a functional operation that is practiced by the computer system of figure 11, the computer system including a memory which stores a pump data model;

[0020] figure 13 illustrates how and why it is sometimes necessary to calibrate the pump data model;

[0021] figures 14 through 16 illustrate how an "optimum" pump-

ing schedule which corresponds to an "optimum" return on investment is determined, a remaining pumping schedule being used (and possibly iteratively modified) to interrogate the calibrated pump data model in order to determine an "optimum" production rate and an "optimum" return on investment.

DETAILED DESCRIPTION

[0022] Referring to figure 1, a perforating gun 10 is disposed in a wellbore 12 and a packer 14 isolates a plurality of shaped charges 16 of the perforating gun 10 downhole in relation to the environment uphole. The shaped charges 16 detonate and a corresponding plurality of perforations 18 are produced in a formation 20 penetrated by the wellbore 12.

[0023] Referring to figure 2, when the formation 20 is perforated, a fracturing fluid 22 is pumped downhole into the perforations 18 in accordance with a particular pumping schedule 24. An example pumping schedule is illustrated in figures 9 and 14. In response thereto, the formation 20 surrounding the perforations 18 is fractured (see figure 9 for an example of a fracture surrounding the perforations 18 in the formation 20 which is created in response to the pumping of the fracturing fluid 22 into the perforations

18 in accordance with the pumping schedule 24).

[0024] Referring to figure 3, when the formation 20 surrounding the perforations 18 is fractured, oil or other hydrocarbon deposits 26 begin to flow from the fractures, into the perforations 18, into the wellbore 12, and uphole to the surface. The oil or other hydrocarbon deposits flow at a certain "production rate" 28 (in barrels/day) thereby generating a "return on investment" 30. A client or owner of the wellbore 12 will want to know the return on investment 30 in connection with the production rate 28 of figure 3 in order to further determine whether to continue producing the hydrocarbon deposits 26 from the wellbore 12. In fact, the client has an "optimum" return on investment in mind and hopes that the wellbore 12 of figure 3 will achieve an "optimum" production rate 28 that corresponds to the "optimum" return on investment.

[0025] Referring to figures 4, 5, and 6, one method for determining an "optimum" pumping schedule for producing oil or other hydrocarbon deposits at an "optimum" production rate and thereby achieving an "optimum" return on investment is illustrated.

[0026] In figure 4, a fracturing fluid 22a is pumped into perforations 18 in the formation 20 in accordance with a first

pumping schedule (pumping schedule 1) 24a. Responsive thereto, oil and other hydrocarbon deposits 26 begin to flow from the fractured formation 20, into the perforations 18, into the wellbore 12, and uphole to the surface at a first production rate (production rate 1) 28a thereby achieving a first return on investment (return on investment 1) 30a. However, assume that the first return on investment (return on investment 1) 30a is not an "optimum" return on investment from the client/wellbore owner"s point of view. Therefore, the first pumping schedule (pumping schedule 1) 24a is not the "optimum" pumping schedule. As a result, in figure 5, the method of figure 4 (i.e., the method for determining an "optimum" pumping schedule for producing oil or other hydrocarbon deposits at an "optimum" production rate thereby achieving an "optimum" return on investment) is repeated with a different pumping schedule (pumping schedule 2) in an effort to determine an "optimum" pumping schedule for achieving the client/wellbore owner"s "optimum" return on investment.

[0027] In figure 5, a fracturing fluid 22b is pumped into perforations 18 in the formation 20 in accordance with a second pumping schedule (pumping schedule 2) 24b. Responsive

thereto, oil and other hydrocarbon deposits 26 begin to flow from the fractured formation 20, into the perforations 18, into the wellbore 12, and uphole to the surface at a second production rate (production rate 2) 28b thereby achieving a second return on investment (return on investment 2) 30b. However, assume that the second return on investment (return on investment 2) 30b is not an "optimum" return on investment from the client/ wellbore owner"s point of view. Therefore, the second pumping schedule (pumping schedule 2) 24b is not the "optimum" pumping schedule. As a result, in figure 6, the method of figures 4 and 5 (i.e., the method for determining an "optimum" pumping schedule for producing oil or other hydrocarbon deposits at an "optimum" production rate thereby achieving an "optimum" return on investment) is repeated again with a different pumping schedule in an effort to determine an "optimum" pumping schedule for achieving the client/wellbore owner"s "optimum" return on investment.

[0028] In figure 6, a fracturing fluid 22c is pumped into perforations 18 in the formation 20 in accordance with a third pumping schedule 24c. Responsive thereto, oil and other hydrocarbon deposits 26 begin to flow from the fractured

formation 20, into the perforations 18, into the wellbore 12, and uphole to the surface at a third production rate 28c thereby achieving a third return on investment 30c. Assume now that the third return on investment 30c is an "optimum" return on investment from the client/wellbore owner"s point of view. Therefore, the third pumping schedule 24c is the "optimum" pumping schedule. As a result, in figure 6, although the aforementioned method of figures 4 through 6 (for determining an "optimum" pumping schedule for producing oil or other hydrocarbon deposits at an "optimum" production rate thereby achieving an "optimum" return on investment) was repeated a plurality of times in connection with a corresponding plurality of wellbores, that method did successfully determine the "optimum" pumping schedule for achieving the client/wellbore owner"s "optimum" production rate and the client/wellbore owner"s "optimum" return on investment. However, one disadvantage associated with the method of figures 4 through 6 relates to the fact that three wellbores (in our example) were fractured in an attempt to determine the "optimum" pumping schedule that achieves the "optimum" return on investment.

[0029] Referring to figures 7 through 16, the aforementioned

disadvantage associated with the method of figures 4 through 6 (for determining an "optimum" pumping schedule for producing oil or other hydrocarbon deposits at an "optimum" production rate achieving an "optimum" return on investment) is eliminated when the method of figures 7 through 16 (for determining an "optimum" pumping schedule for producing oil or other hydrocarbon deposits at an "optimum" production rate achieving an "optimum" return on investment) is utilized. Recall that the aforementioned disadvantage associated with the method of figures 4 through 6 relates to the fact that a "plurality of wellbores" (three wellbores in our example) were fractured in an attempt to determine the "optimum" pumping schedule that achieves the "optimum" return on investment. In figures 7 through 16, the advantage of the method (for determining an "optimum" pumping schedule for producing oil or other hydrocarbon deposits at an "optimum" production rate achieving an "optimum" return on investment) of figures 7 through 16 relates to the fact that a "single wellbore" is fractured in an attempt to determine the "optimum" pumping schedule for achieving the "optimum" return on investment; and, during the fracturing of that "single wellbore" of figures 7 through 16, the "opti-

mum" pumping schedule for achieving the "optimum" return on investment is determined. Therefore, a method associated with a "single wellbore" for determining an "optimum" pumping schedule for producing oil or other hydrocarbon deposits from the "single wellbore" at an "optimum" production rate thereby achieving an "optimum" return on investment is discussed in the following paragraphs with reference to figures 7 through 16 of the drawings.

[0030] In figures 7 and 8, referring initially to figure 7, a fracturing fluid 32 is pumped into the perforations 18 of a wellbore 12 in accordance with a pumping schedule 34. In figures 7 and 8, the wellbore 12 is referred to as a "particular well 36" in order to emphasize the fact that "one single wellbore" is being fractured during the practice of a new and novel method in accordance with the present invention for determining an "optimum" pumping schedule that achieves an "optimum" production rate and an "optimum" return on investment, where the word "optimum" as in "optimum return on investment" represents a term which can only be defined by the owner of the particular well 36. In figure 8, in response to the fracturing fluid 32 which was pumped into the perforations 18 of the partic-

ular well 36, oil and other hydrocarbon deposits 38 are produced from the particular well 36, the oil or other hydrocarbon deposits 38 flowing from the fractures in the formation 20, into the perforations 18, into the wellbore, and uphole to the surface. The oil or other hydrocarbon deposits 38 flow at a production rate 40 in barrels per day. A graph of that production rate 40 is illustrated in figure 8. In figure 8, the y-axis of the graph of that production rate 40 is the production rate ("prod rate") in barrels/day and the x-axis of the graph of that production rate 40 is "time". The graph of the production rate 40 is divided into two parts: an "actual" production rate 40a associated with an "initial portion of the pumping schedule" 34 of figure 7, and two "predicted" production rates 40b and 40c which would be associated with a "remaining portion of the pumping schedule" 34 of figure 7: a first "predicted" production rate 40b and a second "predicted" production rate 40c. The "actual" production rate 40a (of the oil or other hydrocarbon deposits 38 produced from the particular well 36) reflects the rate at which the oil or other hydrocarbon deposits 38 were actually produced from the particular well 36 in response to the "initial portion of the pumping schedule" 34, that "initial portion of

the pumping schedule" 34 representing the actual pumping of the fracturing fluid 32 into the perforations 18 of the particular well 36. The first "predicted" production rate 40b and the second "predicted" production rate 40c (of the oil or other hydrocarbon deposits 38 produced from the particular well 36) each reflect the rate at which the oil or other hydrocarbon deposits 38 may, sometime in the future, be produced from the particular well 36 in response to the "remaining portion of the pumping schedule" 34, that "remaining portion of the pumping schedule" 34 representing a "future potential pumping" of the fracturing fluid 32 into the perforations 18 of the particular well 36, the "future potential pumping" taking place sometime in the future. Therefore, in figure 8, the "actual" production rate 40a is the result of the actual pumping of a fracturing fluid 32 into the perforations 18 in response to an "initial portion of the pumping schedule" 34 and one of the two "predicted" production rates 40b and 40c may result from the "future potential pumping" of the fracturing fluid 32 into the perforations 18 in response to the "remaining portion of the pumping schedule" 34, where the "remaining portion of the pumping schedule" 34 has not yet been implemented. If the

first "predicted" production rate 40b will follow the "actual" production rate 40a (sometime in the future) in response to the "remaining portion of the pumping schedule" 34, a "first return on investment" 42 will be the result; however, if the second "predicted" production rate 40c will follow the "actual" production rate 40a (sometime in the future) in response to the "remaining portion of the pumping schedule" 34, a "second return on investment" 44 will be the result. The client/owner of the wellbore will want to "avoid an undesirable return on investment" (see element numeral 46 in figure 8). Assuming that the "second return on investment" 44 is the undesirable one, the client/owner of the wellbore may want to either stop any further pumping of the fracturing fluid 32 into the perforations 18 in accordance with the "remaining portion of the pumping schedule" 34 because of an undesirable return on investment, or that owner of the wellbore may want to modify the "remaining portion of the pumping schedule" 34 for the purpose of achieving a desirable return on investment. The following discussion with reference to figures 9 through 16 will set forth a method and system by which the owner of the wellbore can determine if an "optimum remaining pumping schedule" associated

with pumping schedule 34 can be determined (for the particular "single" well 36) that will achieve an "optimum" production rate and an "optimum" return on investment.

[0031] In figures 9 and 10, the pumping schedule 34 includes an "initial pumping schedule" 34a and a "remaining pumping schedule" 34b. In figure 9, fracturing fluid and proppant 48 is pumped into the perforation(s) 18 of the particular well 36 in accordance with the "initial pumping schedule" 34a. In response thereto, a fracture system 50 is created in the formation around the perforations(s) 18. In figure 9, micro-seismic data sensor(s) 52 and tiltmeter data sensor(s) 54 are located adjacent the fractures 50. The micro-seismic data sensor(s) 52 and the tiltmeter data sensor(s) 54 are adapted to respectively generate output signals 52a and 54a in response to the creation and further development of the fractures 50, the output signals 52a and 54a being communicated to the surface. In figures 9 and 10, the micro-seismic data sensor(s) 52 are adapted to generate output signals 52a that are communicated to the surface (in response to the creation and further development of the fractures 50) representing "micro-seismic data" 52b; and the tiltmeter data sensor(s) 54 are adapted to generate output signals 54a that are communicated to

the surface (in response to the creation and further development of the fractures 50) representing "tiltmeter data" 54b. In figures 9 and 10, the "initial pumping schedule" 34a, the tiltmeter data 54b, and the micro-seismic data 52b are "time line merged" via a "time line merging" block 56 in figures 9 and 10 wherein a first portion of the tiltmeter data 54b and a first portion of the micro-seismic data 52b are associated with a first time of the initial pumping schedule 34a, and a second portion of the tiltmeter data 54b and a second portion of the micro-seismic data 52b are associated with a second time of the initial pumping schedule 34a, and a third portion of the tiltmeter data 54b and a third portion of the micro-seismic data 52b are associated with a third time of the initial pumping schedule 34a, etc. That is, the tiltmeter data 54b and the micro-seismic data 52b are synchronized with respective times on the initial pumping schedule 34a. In response thereto, a signal representing a "time line merged initial pumping schedule, tiltmeter data, and micro-seismic data" 58 is provided as "input data" to a computer system 60 located in a well logging truck 62 situated at the earth"s surface.

[0032] In figure 11, the computer system 60 of figures 9 and 10

is illustrated. The computer system 60 includes a processor 60a operatively connected to a system bus, a recorder or display device 60b operatively connected to the system bus, and a program storage device 60c operatively connected to the system bus. The "time line merged initial pumping schedule, tiltmeter data, and micro-seismic data" (plus other data including downhole temperature and bottom hole pressure) 58 is provided as "input data" to the computer system 60. The program storage device 60c stores a "bottom hole sensors answer product software" 60c1, the "bottom hole sensors answer product software" 60c1 further including a "pump data model" 60c2. When the processor 60a of the computer system 60 executes the "bottom hole sensors answer product software" 60c1 stored in the program storage device 60c, the recorder or display device 60b will record or display a "diagnostic display" 60b1. The "pump data model" 60c2 and the "diagnostic display" 60b1 will be discussed later in this specification. The computer system 60 of figure 11 may be a personal computer (PC), a workstation, or a mainframe. Examples of possible workstations include a Silicon Graphics Indigo 2 workstation or a Sun SPARC workstation or a Sun ULTRA workstation or a Sun BLADE

workstation. The program storage device 16c is a memory or other computer readable medium which is readable by a machine, such as the processor 60a. The processor 60a may be, for example, a microprocessor, microcontroller, or a mainframe or workstation processor. The program storage device 60c, which stores the Bottom Hole Sensor Answer Product software 60c1, may be, for example, a hard disk, ROM, CD-ROM, DRAM, or other RAM, flash memory, magnetic storage, optical storage, registers, or other volatile and/or non-volatile memory.

[0033] In figure 12, a block diagram is illustrated which represents a functional operation that is performed when the "bottom hole sensors answer product software" 60c1 is executed by the processor 60a of the computer system 60 of figure 11. In figure 12, when the "bottom hole sensors answer product software" 60c1 is executed by the processor 60a of the computer system 60 of figure 11, the received "input data" (representing the "time line merged initial pumping schedule, tiltmeter data, and micro-seismic data" 58) is split into three parts: the initial pumping schedule 34a, the tiltmeter data 54b, and the micro-seismic data 52b, the initial pumping schedule 34a being provided as "input data" to the "pump data model"

60c2. The "pump data model" 60c2, which constitutes a portion of the "bottom hole sensors answer product software" 60c1, is a modeling or simulation program. In response to the initial pumping schedule 34a, the "pump data model" 60c2 portion of the "bottom hole sensors answer product software" 60c1 will generate a set of "pump data model fracture characteristics" 64. The "pump data model fracture characteristics" 64 include the following information representing characteristics of the fracture 50 in figure 9 (see element numeral 64a in figure 12): fracture length (the length of fracture 50 shown in figure 9), fracture height, fracture width, fracture volume (hydraulic and propped), treating pressure, net pressure, bottom hole pressure, temperature, tilts from modeling, and/or pump parameters. In response to the tiltmeter data 54b, the "bottom hole sensors answer product software" 60c1 will generate a set of "tiltmeter data fracture characteristics" 66. The "tiltmeter data fracture characteristics" 66 include the following information representing characteristics of the fracture 50 in figure 9 (see element numeral 66a in figure 12): fracture length, fracture height, fracture width, fracture volume, and/or orientation with respect to the tiltmeter 54 in figure 9. In response to the micro-

seismic data 52b, the "bottom hole sensors answer product software" 60c1 will generate a set of "micro-seismic data fracture characteristics" 68. The "micro-seismic data fracture characteristics" 68 include the following information representing characteristics of the fracture 50 in figure 9 (see element numeral 68a in figure 12): fracture length, fracture height, fracture width, fracture volume and/or orientation with respect to the micro-seismic data sensor 52 in figure 9. In response to the "pump data model fracture characteristics" 64, the "tiltmeter data fracture characteristics" 66, and the "micro-seismic data fracture characteristics" 68, the "bottom hole sensors answer product software" 60c1 will then generate the "diagnostic display" 60b1 which is recorded or displayed on the "recorder or display device" 60b of the computer system 60 of figure 11. However, if the "pump data model fracture characteristics" 64 do not substantially match the "tiltmeter data fracture characteristics" 66 and the "micro-seismic data fracture characteristics" 68, the "pump data model" 60c2 itself may need to be calibrated.

[0034] In figure 13, a block diagram is illustrated which represents a calibration procedure for calibrating the "pump data model" 60c2. In figure 13, it was noted above that, if

the "pump data model fracture characteristics" 64 do not substantially match the "tiltmeter data fracture characteristics" 66 and the "micro-seismic data fracture characteristics" 68, the "pump data model" 60c2 itself may need to be calibrated. Figure 13 represents a calibration procedure for calibrating the "pump data model" 60c2. In figure 13, refer to step 70: if the "pump data model fracture characteristics 64 do not substantially match the tiltmeter fracture characteristics 66 and the micro-seismic data fracture characteristics 68, calibrate the "pump data model" 60c2. In step 72, when calibrating the "pump data model" 60c2, monitor the diagnostics display 60b1 and simultaneously change at least some of the characteristics of the "pump data model" 60c2 thereby creating a "modified"pump data model 60c2; for example, change the following characteristics of the "pump data model" 60c2: (1) the "rock properties", and (2) the "friction of the proppant in the wellbore". In step 74, interrogate the "modified"pump data model 60c2 using the initial pumping schedule 34a (a step which is shown in figure 12) thereby creating a "modified"set of "pump data model fracture characteristics" 64. In step 76, do the "modified"set of "pump data model fracture characteristics" 64 substan-

tially match the "tiltmeter data fracture characteristics" 66 and the "micro-seismic data fracture characteristics" 68? If no, repeat steps 72, 74, and 76. If yes, step 78 indicates that the "pump data model" 60c2 is now calibrated.

[0035] Now that the "pump data model" 60c2 is properly calibrated, the "remaining pumping schedule" 34b of figure 9 will now be used to interrogate the calibrated "pump data model" 60c2 for the purpose of determining the "pump data model fracture characteristics" 64 associated with the "remaining pumping schedule" 34b including the "production rate" and the "return on investment" associated with the particular well 36 of figure 9. In response thereto, the owner of the particular well 36 can determine whether the particular well 36 will ultimately produce an "optimum"return on investment.

[0036] In figure 14, the pumping schedule 34 of figure 9 is illustrated again. The pumping schedule 34 includes an initial pumping schedule 34a and a remaining pumping schedule 34b.

[0037] In figure 15, the remaining pumping schedule 34b is used to interrogate the pump data model 60c2 (in the manner illustrated in figure 12) to determine a production rate and a return on investment for the particular well 36 of

figure 9. The owner of the particular well 36 hopes: (1) that the production rate will be an "optimum" production rate, and (2) that the return on investment will be an "optimum" return on investment. In figure 15, if all goes well, in steps 80, 82, 84, and 86, the "remaining pumping schedule" 34b of figure 14 (step 80) interrogates the "pump data model" 60c2 of figure 12 (step 82) thereby producing a production rate which, hopefully, is an "optimum" production rate (step 84) and a return on investment which, hopefully, is an "optimum" return on investment (step 86).

[0038] However, if the aforementioned production rate of step 84 in figure 15 is not an "optimum" production rate, and if the aformentioned return on investment of step 86 in figure 15 is not an "optimum" return on investment, it may be necessary to change some of the characteristics of the remaining pumping schedule 34b in figure 14 in order to ensure that the "pump data model" 60c2 of step 82 in figure 15 will produce an "optimum" production rate and an "optimum" return on investment.

[0039] In figure 16, therefore, when the "pump data model" 60c2 of step 78 in figure 13 is properly calibrated, the following steps should be taken in order to ensure that the "pump

data model" 60c2 produces an "optimum" or "acceptable" production rate and an "optimum" or "acceptable" return on investment. In step 88 of figure 16, when the "pump data model" 60c2 is calibrated, determine the "remaining pumping schedule" 34b and use the "remaining pumping schedule" 34b to interrogate the "pump data model" 60c2. In step 90, interrogate the "pump data model" 60c2 using the "remaining pumping schedule" 34b. In step 92, determine a new set of "pump data model fracture characteristics" 64 of figure 12 corresponding to the "remaining pumping schedule" 34b. In step 94, determine a "production rate" corresponding to the "remaining pumping schedule" 34b. In step 96, determine a "return on investment" corresponding to the "production rate". In step 98, is the "return on investment" determined in step 96 an "acceptable" or "optimum" return on investment? If no, in step 100, recalling from figure 14 that the "pumping schedule" 34 includes a "frac fluid" column and a "proppant" column, change the proportions of "frac fluid" and "proppant" in the "remaining pumping schedule" 34b to determine a "new remaining pumping schedule". In step 102, use the "new remaining pumping schedule" to interrogate the "pump data model" 60c2 (in the manner illus-

trated in figure 12). Repeat steps 90, 92, 94, and 96 to determine a "new return on investment". In step 98, is the "new return on investment" an "acceptable" or "optimum" return on investment? If yes, in step 104, the "new remaining pumping schedule", which produced the "new return on investment", corresponds to an "acceptable" or "optimum" return on investment.

[0040] A functional description of the operation of the present invention will be set forth in the following paragraphs with reference to figures 1 through 16 of the drawings.

[0041] The present invention pertains to a method and system for determining an optimum pumping schedule corresponding to an optimum return on investment when fracturing a formation penetrated by a wellbore. A pumping schedule is selected for pumping fracturing fluid into a plurality of perforations in a formation penetrated by a wellbore. When the formation is fractured, a production rate and a return on investment is determined for the particular well. However, that production rate and return on investment is a function of the pumping schedule selected. If an "optimum" pumping schedule is selected for fracturing the plurality of perforations in the formation penetrated by the wellbore, an "optimum" production rate

(i.e., the rate at which the oil or other hydrocarbon deposits are produced from the fractured perforations) is produced and, as a result, an "optimum" return on investment is the result, where the term "optimum" is determined by the owner of the wellbore. The "optimum" pumping schedule has been determined by selecting a plurality of pumping schedules for a respective plurality of wellbores and, after fracturing the perforations in those plurality of wellbores, eventually determining the "optimum" pumping schedule that corresponds to the "optimum" return on investment". However, a plurality of wellbores are utilized during the above-referenced practice of determining the "optimum" pumping schedule that corresponds to the "optimum" return on investment.

[0042] A better method (for determining an "optimum" pumping schedule that corresponds to an "optimum" production rate and an "optimum" return on investment) would involve determining the "optimum" pumping schedule that corresponds to the "optimum" return on investment for "one particular wellbore", and not for a plurality of wellbores as previously described. According to this better method, a "particular pumping schedule" 34 is divided into an "initial pumping schedule" 34a and a "remaining

pumping schedule" 34b; and "one particular wellbore" 36 is selected to be fractured in accordance with that "particular pumping schedule" 34. The Earth formation penetrated by the "one particular wellbore" 36 is perforated in the manner described above with reference to figure 1 of the drawings. Then, the resulting perforations 18 in the formation penetrated by the "one particular wellbore" 36 are fractured in accordance with the "initial pumping schedule" 34a in the manner described above with reference to figures 2 and 9 of the drawings thereby producing a fracture system 50 in the formation. A set of micro-seismic data sensor(s) 52 and a set of tiltmeter data sensor(s) 54 are placed adjacent the fractures 50, as shown in figure 9 of the drawings. The micro-seismic data sensor(s) 52 generate a plurality of micro-seismic data 52a and the tiltmeter data sensor(s) 54 generate a plurality of tiltmeter data 54b. The "initial pumping schedule" includes a plurality of times, as shown in figure 9 of the drawings. The "initial pumping schedule" 34a, the tiltmeter data 54b, and the micro-seismic data 52b then undergo "time line merging" 56 of figure 9, wherein, the plurality of tiltmeter data 54b and the plurality of micro-seismic data 52b which corresponds, respectively, to the plurality of times

of the "initial pumping schedule" 34a are determined. As a result of the aforementioned "time line merging" 56, a "time line merged initial pumping schedule, tiltmeter data, and micro-seismic data" output signal 58 is generated. The "time line merged initial pumping schedule, tiltmeter data, and micro-seismic data" output signal 58 is provided as an "input signal" to a computer system 60 of a well logging truck 62, as shown in figures 9 and 10. In response to the "time line merged initial pumping schedule, tiltmeter data, and micro-seismic data" output signal 58, the processor 60a of the computer system 60 in the well logging truck 62 executes a stored software called the "Bottom Hole Sensors Answer Product Software" 60c1 that includes a "pump data model" 60c2. In response to the execution of the stored software 60c1 by the processor 60a, as shown in figure 12, the "initial pumping schedule" 34a will interrogate the "pump data model" 60c2 and thereby generating the "pump data model fracture characteristics" 64, the tiltmeter data 54b will generate the "tiltmeter data fracture characteristics" 66, and the micro-seismic data 52b will generate the "micro-seismic data fracture characteristics" 68. In figure 12, the "pump data model fracture characteristics" 64, the "tiltmeter data

fracture characteristics" 66, and the "micro-seismic data fracture characteristics" 68 will collectively generate a "diagnostic display" 60b1 that is recorded or displayed on the recorder or display device 60b of the computer system 60 disposed in the well logging truck 62. If the "pump data model fracture characteristics" 64 of figure 12 do not substantially match the "tiltmeter data fracture characteristics" 66 and the "micro-seismic data fracture characteristics" 68, the "pump data model" 60c2 of figures 11 and 12 must be calibrated in the manner described above with reference to figure 13 of the drawings. When the "pump data model fracture characteristics" 64 of figure 12 substantially matches the "tiltmeter data fracture characteristics" 66 and the "micro-seismic data fracture characteristics" 68, the "pump data model" 60c2 is calibrated. At this point of the novel method of the present invention, referring to figures 14 and 15, the "remaining pumping schedule" 34b of the pumping schedule 34 interrogates the calibrated "pump data model" 60c2 and, hopefully, an "optimum" production rate for the particular well 36 of figure 9 is determined and an "optimum" return on investment for the particular well 36 of figure 9 is also determined. In figure 16, if the "optimum" production rate and the "opti-

mum" return on investment is not determined when the "remaining pumping schedule" 34b of figure 14 fractures the perforations 18 of the particular wellbore 36 of figure 9, as shown in figure 16, change the proporations of the "frac fluid" and the "proppant" in the "remaining pumping schedule" 34b of figure 14 (see block 100 of figure 16) to thereby create a "new remaining pumping schedule" and then use the resultant "new remaining pumping schedule" to interrogate the "pump data model" 60c2 (see block 102 of figure 16). If the resultant "production rate" and the resultant "return on investment" are acceptable (i.e., an "optimum" production rate and an "optimum" return on investment are generated), the owner of the particular wellbore 36 of figure 9 must now consider whether or not to continue to actually fracture the particular wellbore 36 using either the "remaining pumping schedule" 34b or the "new remaining pumping schedule" in the manner described above with reference to figure 2 of the drawings.

FUNCTIONAL SPECIFICATION FOR THE BOTTOM HOLE SENSORS ANSWER PRODUCT SOFTWARE 60C1

[0043] A functional specification associated with the "Bottom Hole Sensors Answer Product Software" 60c1 of figure 11 will be set forth in the following paragraphs:

[0044] User interactions are performed through the Recorder or Display Device 60b in Figure 11. Where a specification indicates a display, it refers to this device and where it refers to the User doing something it infers interaction with this device. The display is a terminal screen and the input device can be a keyboard, mouse or a touch screen. Where the input device is a touch screen, the input device and the terminal screen are the same thing.

[0045] Timeline merging (56 in Fig. 10 and 58 in Fig. 11)

[0046] 1. The pump parameters are treated as the Primary Source, this serves as the timeline for the merged data-set.

[0047] 2. All other sources (e.g. microseismic, tiltmeter, bottom hole pressure, temperature etc.) are considered as Secondary Sources.

[0048] 3. Data from Secondary Sources is intially buffered.

[0049] 4. The time location for an observation in the Secondary Source is read from the buffer.

[0050] 5. The corresponding time is located in the Primary Source

[0051] 6. The information from the Secondary Source buffer is appended to the Primary Source information at the correct time, creating the Merged Data Set.

[0052] 7. This operates continuously during real-time data acquisition so that the Merged Data is continuously available for processing.

[0053] 8. If Secondary Source data appears with timestamps more recent than the more recent Primary Source data, it is buffered until needed.

[0054] 9. If the Primary Source ends (or fails), one of the Secondary Sources will be selected, by the user, to become the Primary Source so that data-merging can continue.

[0055] Pump Data Model Fracture Characteristics (64 and 64a in Fig. 12 and 60c2 in Figure 11)

[0056] 1. The forward model includes information on rock properties, such as Young"s Modulus, in-situ stress, Poisson"s Ratio, permeability, reservoir pressure etc.

[0057] 2. There are multiple available fracture models (1-, 2- and 3-dimensional) and the user selects whichever is most appropriate for the current job.

[0058] 3. This is a numerical model based on physical principles

[0059] 4. The model is used to create predictions of the possible observables such as the examples listed in 64a of Figure 12.

[0060] 5. These output predictions are stored ready for display along-side observations for comparison.

[0061] Tiltmeter Data Fracture Characteristics (66 in Fig. 12)

[0062] 1. An inversion algorithm is used to calculate the size and shape of the distortion that resulted in the tilt.

[0063] 2. There are multiple such algorithms avialable and the user selects whichever is most appropriate for the current job.

[0064] Microseismic Data Fracture Characteristics (68 and 68a in Fig. 12)

[0065] 1. The user can view the microseismic event locations in three orthogonal two-dimensional views (East vs. North, North vs. Depth and East vs. Depth).

[0066] 2. Interactively the user may draw a box around a sub-set of the microseismic points, relating to the hydraulic fracture.

[0067] 3. The interpretation in step 2 allows the experienced user to differentiate microseismic events from the fracturing from, say, events generated by movement of an existing fault plane nearby.

[0068] 4. The microseismic points lying inside a particular interpretation box are considered as an interpretation set.

[0069] 5. For each interpretation set, the minimum-distance least-squares line through the points is considered to be the interpreted axis of the fracture.

[0070] 6. The center of the fracture is considered to be located at the mean position of the microseismic events in the interpretation box.

[0071] 7. The length of the fracture is determined by the furthest distance of a microseismic event along the interpreted axis in either direction.

[0072] 8. The length is stored in each direction as a half-length, so that asymmetry of the fracture may be determined.

[0073] 9. The height of the fracture is determined by the further distance of a microseismic event perpendicular to the axis along the minimum-distance least-squares plane through the points.

[0074] 10. The height is stored in each direction from the center as a half-height, so that again symmetry can be analyzed.

[0075] 11. The elliptical area of the fracture is determined from the length and height information.

[0076] 12. The rectangular area of the fracture is determined from the length and height information.

[0077] 13. The orientation of the fracture is determined as the orientation of the interpreted axis.

[0078] 14. The fracture characteristics determined from the microseismic information are stored (by 60c in Figure 11).

[0079] Diagnostic Display (60b1 in Figure 11 and Figure 12)

[0080] 1. The diagnostic display is completely configurable in terms of which graphs are displayed.

[0081] 2. The configuration for a particular job contains graphs that compare stored information. This can be observations, results from the Pump Data Model (64 and 64a in Figure 12), results from the Tiltmeter Data (66 and 66a in Figure 12), results from the Microseismic Data (68 and 68a in Fig. 12)

[0082] 3. The interaction for the user to intepret fracture characteristics from microseismic described above, can be achieved using a diagnostic plot.

[0083] 4. Diagnostic plots can carry automatic alarms. These alarms can be triggered by any information trigger (for example greater-than, less-than a value; difference between modeled and observed values of the same property etc.) see 70 in Fig. 13

[0084] 5. The alarms alert the user immediately to early-warning signals that the original operation is not producing the desired results.

[0085] 6. Alarms can be set for any observation, any fracture characteristic derived from observation, or any model output.

[0086] 7. Alarms can be created for any mathematical combina-

tion of the values described in step 6.

[0087] 8. The Diagnostic Displays can show predictions based on the portion of the pump schedule not yet pumped.

[0088] 9. The Diagnostic Displays can show results from production simulation and return on investment.

[0089] Calibration of the pump model (72, 74, 76 and 78 in Figure 13)

[0090] 1. The user decides to perform a calibration, and so clicks on the "Calibrate"button to initiate the process.

[0091] 2. The pump schedule is split into the fixed portion (that which has been pumped so far 34a in Fig. 14) and the remaining portion (that which is yet to be pumped 34b in Fig. 14).

[0092] 3. Concentrating on the fixed portion, the user can further split the pumpshcedule into calibration intervals.

[0093] 4. The user selects a match-point within each calibration interval (in time) where the obesrvations and the model will be compared.

[0094] 5. The user selects the appropriate quantity (rock properties or friction of the proppant) to vary to achieve the match.

[0095] 6. The program iteratively adjusts the appropriate quantity to improve the match at the define match-points until

the root-mean-square difference between the modeled and measured values is below a user-defined limit. This is an iterative optimization.

[0096] 7. Once the match is good as defined in step 6., the Pump Data Model is considered to be calibrated and useful for predictions.

[0097] Optimizing the remaining pump schedule

[0098] 1. The fixed portion and remaining portion of the pump schedule (80 in Figure 15) are used with the Pump Data Model to provide a prediction for the current job.

[0099] 2. The output from the Pump Data Model includes a propped fracture length and a fracture conductivity. It is the fracture characteristics resulting from completing the current job with the remaining portion of the pump schedule (90 in Figure 16)

[0100] 3. The fracture length and conductivity, along with rock properties are inputs to a production simulator (84 in figure 15).

[0101] 4. The production simulator is a numerical simulator that uses mass-balance and flow equations to model the predicted flow of hydrocarbons through the well during reservoir production.

[0102] 5. There are several production simulators available and

the user selects the most appropriate one for this job.

[0103] 6. The production simulator uses specified well controls (for example a constant draw-down pressure) to numerically model the production expected from the fractured well.

[0104] 7. The output of the production simulator is the production vs. time (commonly known as the Decline Curve (the "Production Rate" in 94 of Figure 16). It may also include other production parameters, such as water-cut versus time.

[0105] 8. The outputs from the production simulator are forwarded to the Return On Investment calculation (86 in Figure 15).

[0106] 9. The return on investment considers the cost of the fracture treatment and the monetary value of the decline curve, plus any costs associated with handling unwanted production (such as the water-cut). These are the known costs.

[0107] 10. The return on investment simulator is a numerical simulator that provides a monetary value over time for the results of the fracturing.

[0108] 11. There are several ways to calculated return on investment available. The user selects the most appropriate.

[0109] 12. The return on investment provides an output of return versus time from the production data and the known costs. (96 on Figure 16)

[0110] 13. An adjustment is made to the fluid and proppant pumped in the remaining portion of the pump schedule. This is made under the constraint of the total materials available at the well-site minus the total materials pumped so far (102 on Figure 16).

[0111] 14. Steps from 1 through 13 are repeated iteratively to improve the return on investment in line with the client"s definition of an "optimum"return. (98 on Figure 16). The results of each iteration are used in calculating the best updates to make in step 13, so that this scheme converges to the optimum solution over a few iterations.

[0112] 15. The remaining portion of the pump schedule that has been determined by the above scheme represents an optimum alternative to the original remaining portion of the pump schedule (104 in Figure 16).

[0113] 16. A graphical display contrasts the return on investment for continuing with the original remaining portion or, instead, using the newly determined remaining portion.

[0114] 17. The client is then able to select between the alternatives, and any changes are relayed to the pump operator.

[0115] 18. This calibration and optimization scheme can be re-calculated at any time during the job. The portion of fixed schedule being determined at the time the user begins to calibrate.

[0116] 19. The calibration and optimization are rapid operations compared to the length of the pump schedule.

[0117] The invention being thus described, it will be obvious that the same may be varied in many ways. Such variations are not to be regarded as a departure from the spirit and scope of the invention, and all such modifications as would be obvious to one skilled in the art are intended to be included within the scope of the following claims.